

WG-K3-Transm– 3/20/14

Reducing Outages Through Improved Protection, Monitoring, Diagnostics and Autore Restoration In Transmission Substations- (69kV and above)

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9. Bibliography & References
10. Appendix A- Reliability Indicators
11. Appendix B- Characteristics of Microprocessor Relays
12. Appendix C- Discussions
 - Switching of generator breakers or autotransformer source lines
 - Sudden Pressure Relay (SPR)/ Fault Pressure Relay (FPR)] actions
 - Thermography (IR) Cameras – Hot spot detection and trending

Outline:

1. Introduction & Evolution of Protection Schemes
2. Transmission Events and Outage Reduction
3. Preventing the Event From Occurring in the First Place
4. Some of the Diagnostic or Predictive Functions that can be Utilized
5. Communication
6. Oscillography and Sequence of Events Capabilities of Micro-processor Relays
7. Timestamping and Resolution
8. Transformer and Circuit Breaker Reliability Monitoring Capabilities of Microprocessor Relays

1. Introduction

This discussion will primarily address the subject of reducing outages or reducing the outage duration, auto-restoration applications for transmission substations, (where “transmission” is defined as 69kV and higher), and the subject of proactively preventing outages. This paper follows the work performed by the K3-WG for distribution systems titled “Reducing Outage Durations Through Improved Protection and Autorestation in Distribution Substations”. [1]

As protection technology evolved, movement away from the electro-mechanical relay protection scheme changed as well. Electromechanical relays gave way to the progression of solid state relays, to the microprocessor (MP) relay or Intelligent Electronic Device (IED), and then to the evolution of the multifunctional MP relay system.

In this type of device the entire protection package has moved from multiple devices that had to be wired together, to a single device which contained multiple functions and applications. The single device concept may be limited only by the need for redundancy or primary and secondary protection considerations to cover the contingencies of a single device failure.

Self-checking diagnostics continuously monitor the health of the components within the MP relay, generally everything with the exception of the actual inputs and the output contact health.

Cost reductions can be realized both by the reduction of external wiring between relays and panels, and also through the built-in health diagnostics monitoring, allowing for reduced maintenance tests.

Forms of programmable logic control have manifested themselves with names such as input/output logic, ladder logic, and similar terms.

Input/output logic (I/O) can perform what could be construed as adaptive functions to some

extent. Adaptive settings can react to load level changes as well as defined outside weather conditions and adjust accordingly. Taking advantage of these new functions offers reliability enhancements to remove failure-prone auxiliary relays, trip circuit monitoring relays, diodes and capacitors spread out through the control panels, and give way to I/O circuits internal to the MP relay package.

Relay communications can take place over serial or network circuits. The relays can be time synchronized to GPS time. This should allow comparison of all fault records and sequence of events files to analyze events that take place.

While the digital fault recorder (DFR) once was the only source of oscillographic waveform data and sequence of event data, a subset of that functionality for that protection package can now be obtained from the MP relay. The need for the station DFR system still plays a big part in fault analysis and misoperation investigation. However, the internal sequence of event data records and logic time tagging enhances what is typically available on a station DFR.

The MP relay can be interrogated remotely; settings and data files retrieved, and control functions are available. File comparison software exists to verify that the setting file in the relay matches the setting file that the user thinks was installed on the relay.

With remote communications functionality comes the task of protecting for cyber security to avoid unauthorized access to the MP relay. IEEE-PSRC Working Group WG I18 ‘Anomaly Checks for Relay Settings’ [2] provides guidance on relay software features and setting practices that minimize the possibility of wrong settings being downloaded to a relay, based on surveys of relay manufacturers and utilities. Best practices for preventing unintentional errors and malicious tampering of relay settings are provided.

2. Transmission Events and Outage Reduction Methods

Reducing the transmission event and subsequent outage can be broken down into a few major categories:

- Proactive- Prevent the event from occurring in the first place, thereby eliminating the outage.
- Proactive- Predictive action based upon trending streaming data and setpoints.
- Reactive- Analyze data for follow up analysis that can be acted upon to prevent future similar events from reoccurring. (reactive gathering of data for future proactive action)
- Reactive- Provide real-time information to take control action upon.
- Reactive- Provide automatic control action such as involving one part or another of the functions of trip - isolate – restore, all automatically in order to reduce the outage time.

3. Preventing the Event From Occurring in the First Place- Proactive

Some of the obvious prevention techniques fall into these areas:

- Physical- tree trimming and foreign object guarding; animal and bird guarding and detection; contamination avoidance- washing or adopting the use of partially conductive glazed insulators; replacing equipment just prior to end of life and before having age-related failures; adequate conductor spacing and anti-galloping conductor swing devices where needed.
- Local diagnostics and health- employing MP relay systems with built-in diagnostics and health monitors- not only just for the individual protection relays themselves, but also for the external equipment that is being protected.
- Diagnostic systems for specific applications.

- Utilizing a Transmission Performance Diagnostic Center (TPDC) to gather data and perform trend analysis in order to take action before the device functionality is impaired.
- Automatic corrective action with the intent to either isolate or restore depending upon specific settings or rules.

4. Some of the Diagnostic or Predictive Functions That can be Utilized.

Protective relays are no longer simply a single function device that only mimics the electromechanical relay function that it replaced. There are other various features built into multifunction relays that enhance the protection.

4.1 Predictive/diagnostic

Other functions being implemented may be valuable in preventing faults or problems before they manifest themselves in failures by detecting an impending or incipient failure. In theory, these detections occurring in early stages could 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 include loose or noisy primary connections, fuse failures, impending arrester or insulator failures, capacitor failures, sporadic foreign interference identification. Incipient splice failure detection in underground cable is already available [3], and similar techniques are being field tested to be able to detect incipient arrester failure as well as incipient capacitor can failures, power transformers and VT failures. Bushing failures have traditionally been predicted through manual testing. Field tests are currently underway to gather data of the in-service predictive impending incidents and conditions. [4] [5] [6]

Partial discharges in transformers are small electrical arcs within the voids, cracks, and spaces, between the insulation and conductor interfaces. A similar phenomena can also occur in

enclosed bus systems. Once begun, this progresses into deterioration of the insulation system leading to electrical breakdown.

In transformers, partial discharges are mainly caused by contaminants 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 resulting in a customer outage [7].

Several devices are currently available to monitor partial discharges on in-service transformers. The monitors can be permanently installed or portable and used as part of a regular transformer inspection routine.

There are breaker restrike schemes to identify or remove circuit breakers from service prior to fatal faults as detected by MP relays. [4]

New MP relay based condition monitoring schemes are in development to detect arcing and incipient faults, their location, and create an alarm. This development is the extension from distribution applications to the transmission system. [5] [6]

Capacitor Voltage Transformers (CVTs) are widely used in place of Voltage Transformers (VTs) in protection schemes. There are methods to detect CVT performance issues, such as with transient response voltage, and CVT failure detection using various relay detection settings, phase angle or phase magnitude change detection, loss of a CVT by monitoring the broken delta voltage (3Vo), sometimes also referred to as the open delta voltage 3Eo) voltage detection, etc.

In addition to transient response detection schemes, the actual health, or rather the failing

health of a CVT is something that might be trended, predicted or detected prior to failure. The loss of a normal CVT can lead to abnormal voltage being supplied to a relay scheme, SCADA system, or State Estimator. If the CVT continues to failure, there normally are three areas affected:

- a. High or low voltage output- usually from a component failure, or stack failure.
- b. Carrier “holes” or loss of carrier signal- generally gaps or drain coil issue.
- c. Violent failure due to stack failure or water intrusion in primary voltage circuit.

In the past, these failures would have been detected during manual assessments at the station on a periodic basis, but new technology in DFRs and MP relays have provided a method to detect abnormal conditions that can be detected or trended for proactive action prior to the failure causing a misoperation or violent failure.

One such method would be detection in a MP relay with flexible logic equation algorithms and set points.

Another method would take advantage of the new DFRs using DNP-3 or similar protocol to send data back to a data repository for use in a TPDC where automatic trending of the station values can take place in real time where preprogrammed actions could be taken proactively, and automatically inform the appropriate personnel to investigate and take action. The huge advantage with this system is to automatically monitor trending and to take evasive corrective action prior to becoming fatal or to cause a misoperation.

Substation battery and battery charger conditions can be continuously monitored and analyzed so that incipient problems can be detected and remedial actions be taken to avoid major problems.

MP relays may be used to monitor the transmission system and provide an alarm for an open phase condition, which may occur when one

blade of a three-phase line disconnect switch does not close completely or when a line conductor jumper burns open. The relay can be programmed to provide an open phase alarm when it detects excessive negative-sequence current in the presence of balanced voltages (i.e. the absence of negative sequence voltage) when all poles of the breaker are closed. The open phase alarm logic is typically implemented with a time-delay, and the negative sequence current detector must be set greater than typical system imbalance.

Thermography tests are another tool for detection of abnormal temperature or contrasts in temperature. Normal use would be performed as a manual hand-held test tool. Automation and data trending could be another valuable tool. Refer to Appendix C for discussion.

4.2 Restoration techniques

The reduction in restoration time can be the result of outage reduction or by minimizing the extent of damage by using simple reactive or more complex logic techniques.

Communication or control schemes between relays, breaker failure to transformer schemes and similar “communications” between the relays can reduce operating times and thus reduce damage and further outage time. For example, in the earlier electromechanical contact world, a breaker failure scheme would minimize equipment damage using a control scheme where one area of protection operated another. In the MP relay world, communications between MP relays could take advantage of various communications protocols and messaging techniques, goose messages, or future defined communications messaging for one relay to communicate to another relay.

SCADA reclosing in coordination with line panel scheme reclosing assumes that a fault is temporary if there was no indication of multiphases being involved and breaker went through normal reclose-trip. This type of scheme coordinates with the SCADA close attempts with

automatic reclosing, which initiate only if multiphases are not involved. It gives another attempt at restoring a line following a temporary fault. This function was developed for line panel systems that only employ single shot reclosing and this further enhances the system by automatically closing the breaker without operator interaction.

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 lead reclosing breaker, which attempts the reclosing sequence. If the first breaker successfully recloses, the second breaker may be programmed to follow to then reclose to complete the ring bus.

Another use of a ring bus may include a transformer or another line circuit between the two ring breakers. Automatically opening a motor operated disconnect switch on this circuit with the breakers open would then allow for automatic reclosing of the ring breakers, establishing the transmission ring. Similar schemes can be used for breaker-and-a-half configurations. [8]

Single-phase tripping (SPT) is used to open the faulted phase during a single-line to ground fault.[9] It is well known that single line to ground faults are the most common types of faults accounting for 70% of all instances and in the case of 500kV transmission lines they account for 93% of all instances due to the increased spacing of the EHV conductors.[10] With SPT the system stability may be improved because the power transfer is maintained, albeit at a lower level on the two unfaulted phases during an the clearing of a single line-to-ground fault. This allows for the system to remain synchronized and for power to be transferred during a single-line-to-ground fault condition [10] [11]. For the benefits of SPT the fault must be cleared, any remaining secondary arc must also be cleared, and the line must be reclosed. The two most difficult challenges with a

single-phase scheme are proper selection of the faulted phase and not tripping the other phases or other lines during the open phase condition that may occur after the faulted phase is tripped. Phasor Measurement Units (PMUs) are devices capable of providing synchronized phasor quantities from across a power system. The standard C 37.118-2005 or C37.118.1 define the measurement requirements term and C37.118.2 and C37.244 describes network requirements and guidelines to acquire synchrophasor values for various applications.

A synchrophasor is defined as “A phasor calculated from data samples using a standard time signal as the reference for the measurement. Synchronized phasors from remote sites have a defined common phase relationship.” As a result, synchrophasors measured across an interconnected power grid will have a common timing reference and thus can be compared directly [12].

According to the standard, a synchronizing source that provides the common timing reference may be local or global. The synchronizing signal may be distributed by broadcast or direct connection, and shall be referenced to Coordinated Universal Time (UTC). One commonly utilized synchronizing signal is the satellite signal broadcast from the Global Positioning System (GPS).

Synchrophasors may be utilized in wide area monitoring, protection and control for improved reliability and reduced outage. Example applications include power swing detection, power stability monitoring, dynamic line thermal rating, and accurate fault location [13] [14] [15] [16]. Data may also be captured for longer time durations as well, which would be very beneficial following widespread system events.

There are several methods in use to detect broken or open conductors, downed conductors, arcing and high impedance faults with various levels of success. This is primarily used on distribution circuits less than 69kV. For further details see references [16] [17] [18] [19]. Downed

conductors or high impedance faults detection includes the use of complex systems that make use of pattern recognition tables and artificial intelligence methodologies.

4.3 Other

IEEE- C37.104- “IEEE Guide for Automatic Reclosing of Line Circuit Breakers for AC Distribution and Transmission Lines” [20] contains many reclosing practices, such as operational techniques or practices for reclosing lines with generation at one end or another of a line, and practices for reclosing lines with autotransformers at one end of a line or another and strong / weak infeed. These two topics are discussed in some detail in Appendix-C.

IEEE C37.233–“IEEE Guide for Power System Protection Testing” and several sections of C37.233 are focused on testing synchronized Reclosing and integrated reclosing, as well IEC 61850 Integration With Reclosing and can be utilized as references.

Multiple settings, setting groups, and even adaptive settings may be offered [21] [22] in the MP or multifunction protection systems. Additional zones of protection can be found in MP relays.

One example of a predictive method is an IED or TPDC system providing the adaptive characteristic of being able to predict the amount of time before a transformer should have load reduced to avoid exceeding overload ratings can then be taken either through remote or local intervention.

Capacitor and reactor bank automatic controls, by measuring voltage and reactive power flow and/or following a pre-determined switching schedule, help with voltage and var control for optimizing the bulk electric system power flows.

Fault location, or distance to fault can be automatically calculated and displayed. [25] [26]. This data can then be passed to the SCADA system where the system operator can initiate sectionalizing to the closest upstream switch or direct work crews to the identified fault location.

By using this data, it is possible to reduce the outage time by locating the fault more quickly. Double-end fault location can take advantage of convergent locations from both ends and provide the confidence to automate the sectionalizing in order to return the transmission line back to service with the minimum section(s) isolated. In cases where only local measurements such as when only single ended data is available, some algorithms may be able to provide reliable fault location estimates [23].

Fault location system may be integrated with other applications for identifying the fault cause. For example, by correlating the fault location result with lightning events provided by a lightning detection system, it may be deduced that the fault is caused by a lightning event.

Trending of fault location analysis results over time may provide input to transmission line maintenance programs to prevent faults and reduce outages, such as tree trimming, conductor clearance, shielding, and animal induced outage preventative measures.

5. Communication

Smart Grid devices, or IEDs, make use of communications to bring back data, which can be used in normal SCADA activities, or brought into a TPDC for trending and predictive diagnostics. Communications can also enhance protection and automation control and provides for high speed control both within and between substations. 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 outages.

Using intelligent relays and communication between devices to provide tripping supervision, breaker failure functions, etc. can aid coordination so that clearing times can be faster.

Relay to relay communication may be accomplished using a dedicated fiber optic

network. Relays that support IEC-61850 can send and receive GOOSE/GSSE (Generic Object Oriented Substation Event-Generic Substation Event) messages over a Local Area Network (LAN) connecting the various relays together , [27] [28]. Cyber Security now has its own subject area, and is addressed mostly through the use of strong passwords, or special permissive hardware schemes that grant access to the devices to authorized users. Unauthorized access could result in relay misoperations or control functions.

6. Oscillography and Sequence of Events (SOE) Capabilities of MP Relays

As a standard feature, MP based 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 may not have enough points to adequately monitor all equipment and logic levels. The extended coverage may go as far as having the same secondary signals recorded by more than one device. Where the data channels are duplicated in multiple monitor records, this allows for confirmation of one record versus the others when troubleshooting problems internal to the relays, secondary circuits, VTs and CTs. Using the recorded analog voltage and current signals and digital points, it is possible to evaluate the performance of the protection system of concern.

Typical characteristics and options related to disturbance recording of MP-based 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.

Electric utility companies routinely install digital fault recorders and event recorders in major transmission substations and power plants to record system events. With new North American Electric Reliability Corporation (NERC) standards

on the horizon, other stations and devices that may not have been monitored before are expected to see new requirements to do so. While not the overall station monitor, the MP relay with its built in oscillographic capability and SOE recording, does give a smaller scale capability to provide recording on specific equipment and provide data for trouble shooting, power quality, maintenance questions, etc. that were not previously available. This has proved to be invaluable in solving some previously unresolved questions that took many costly hours of testing and verification to resolve, if at all.

7. 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 MP based relays may not support accurate time synchronization. Modern high-end relays support time synchronization via GPS/IRIG-B time signals. Typical time accuracy can be in the range of a few microseconds. (Older time clock receivers were in the millisecond accuracy region, however as technologies evolve, microsecond accuracy should become the norm for this function.)

Other means of synchronization include Ethernet-based algorithms such as Simple Network Time 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 was 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 the 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 B-6.

8. Transformer and Circuit Breaker Reliability Monitoring Capabilities of MP Relays

8.1 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 included with MP based relays [29]. 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 part 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. Maintenance parameters can be tracked, such as I^2t or breaker operate times, for determining unscheduled maintenance. This

becomes especially useful when the data is trended and predictive techniques are used to continuously evaluate the data.

Breaker operate time is defined and measured as time elapsed between the trip signal and the breaker main contacts coming open. The pole opening occurs when the current interruption 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 or event report” or “fault location” features of MP 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. Manufacturers generally supply information on their drawings as to where on the opening or closing cycle a specific contact is supposed to operate relative to the main contacts.

Breaker flashover (strike and restrike) monitoring functions are available to monitor open breakers. Corrective actions could be performed for intermittent flashover that otherwise will remain undetected and would tend to eventually lead to failure. [4]

Counters could be set to count breaker operations. Sometimes, increased operations for a given period, or the rate of change of operations within a given time period may indicate an issue that needs to be investigated. For example, a change in the feeder phase load balancing can result in increased neutral current that has resulted in tripping of the breaker. Rebalancing the feeder load can tend to zero out the neutral current if the phase loads approach being equal. 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.

In addition to contact wear, the task of tripping the breaker open during a high fault condition can have an effect on current transformer (CT) remanence (increased magnetic effect and the CT saturation characteristic). The higher the current when it is interrupted, the more likely it is to have an effect on the CTs saturation characteristic. Captured data may aid in evaluating this condition for further investigation. Note that this concern with this CT characteristic would be applicable to all CTs whether in a circuit breaker, transformer, or bus mounted where the CTs are used for protective relaying purposes and CT saturation would be an issue that can affect the performance related to the protective relay system.

8.2 Trip coil monitoring-

Breaker trip coil monitor (TCM) logic can be created using an input and programmable logic of MP relays. This is accomplished by connecting a relay input to monitor continuity in the trip coil circuit when the breaker is closed. Since a trip coil failure is detected as an open circuit (relay input drop-out), relay logic can be used to alarm for a discontinuity in the trip circuit. The TCM logic is typically implemented with a time-delay. This short delay allows time for the breaker or switch to change state after the trip bus is energized and the device changes state without causing momentary alarms.

Local breaker failure and backup protection provides for the failure of a lockout relay (LOR) to trip, or for the failure of a breaker to trip. It may be caused by a stuck LOR that fails to trip or fully close its trip contacts or for blown fuses. In the breaker, the trip coil/circuit or linkage may have gone bad, the mechanism has frozen up, or operates but the interrupters remain closed. In short, the intended device fails to trip and breaker failure or backup protection operates to provide further trip functionality. Where applied, LORs typically trip and block closing of multiple breakers. Alternatively, tripping the necessary

breakers might be done using additional I/O contacts from the primary protective MP relay and also from the MP relay performing this function. Additional contacts might also be needed for breaker failure initiation and for drive-to-lockout. Undesirable manual or automatic closing into a failed breaker should be prevented and this is a consideration of the overall protection system design. [30]

In the case of mechanism or interrupter problems, then the only recourse is to trip the next upstream device. In the MP relay systems, this may be handled by I/O circuits within the MP relay or through relay-to-relay communications.

Communication can also be utilized to accomplish remote breaker failure protection, which could be used between the substation devices as well for isolation of faulted transmission line sections, especially for restoring tapped load stations to a given point in the transmission line.

8.3 Transformers

There are transformer monitoring or diagnostic devices. Due to their relatively high cost they may not be justified for all transformers. Dissolved gas analysis (DGA) detection may be one of the features included in such schemes as well as some bushing monitoring functions. Simple transformer monitoring functions are available in MP based relays at no, or low extra cost.

Transformer life is reduced during periods of overheating or overload. There are schemes that monitor transformer power loading and temperature of the oil, hot spot inferred temperature, or actual sensors embedded in the winding. If the loading and/or temperature exceeds a predetermined value, certain alarms or control actions may be taken. Manufacturer's curves estimate the amount of loss in life for a given excess temperature rise experienced by the transformer. Conventional alarms are usually set for a specific temperature of the oil and of the hot spot; however this is not predictive but rather reactive to the temperature that the transformer has already been exposed to.

Hot spot temperature estimation models are available for predicting the safe overload periods of transformers based on current conditions. 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 can be used in conjunction with devices that use the 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 load, or even trip the transformer.

Transformer thermal models 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 experiencing loss-of-life 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.

A through fault counter can be programmed within a transformer relay to count through-faults, generally tagged as the currents at the time of the relay protection contact assertion for trip. Through-faults tend to degrade transformers via their electro-dynamic flexing and thermal effects. 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.

Counters can be set up to independently count operations of tap changers. Breaker arcing

current features 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 in conjunction with analysis of subsequent failures and events allows for the development of experimental thresholds for relative equipment health. This allows for the prediction of failures with reasonable accuracy in order to optimize spare equipment and schedule retrofits, obtain impartial measures of relative capabilities of various types and manufacturers 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 or stress indices. Breaker and transformer monitoring data produced by modern microprocessor relays seem to be well suited for such software packages.

Sudden Pressure Relays (also referred to as Fault Pressure Relays) are a mechanical device triggered by a rapid change in the transformer tank pressure. This is detailed in Appendix "C". There is the Working Group K6 of the IEEE-PSRC which is doing work on the Sudden Pressure Relays used in transformers. This work is expected to be complete in ~~2013~~ or 2014. Refer to the PSRC website for published reports and minutes for the progress of this group.

Conclusion:

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

High speed fault detection can reduce the fault duration time, and thus limit equipment damage. In many cases, autorestitution techniques can reduce the outage time to the affected customers significantly.

We can take advantage of trending and predictive diagnostics which may prevent an event from taking place by streaming data to a Transmission Performance Diagnostic Center (TPDC) and acting on this data.

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Appendix- A: Reliability Indicators [1]

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

.....
CI: Customers Interrupted

.....
CMI: Customer Minutes of Interruption

.....
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: The 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

MAIFI=

=
$$\frac{\text{Total \#customer momentary interruptions}}{\text{Total no. of customers served}}$$

SAIFI:

System Average Interruption Frequency Index
Frequency of sustained 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 per year.

.....
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 MP Relays [21, 22]

B-1 Relay A/D and Automatic Checking

The analog input component of a MP 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 MP to use. The analog input component is partially checked by the relay self-test feature [23] [24]. 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 (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 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 an 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 AC 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 typically 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

MP based 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 at much lower rate 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 sinusoidal.

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, MP 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.

MP based relays 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.

B-5 Programmability

Some MP 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 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 MP based relays and full-featured DFRs. This may pose limits on the record length in the MP relay.

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

Appendix C: Discussions

Generator and autotransformer switching with regard to strong and weak source lines:

Strong versus weak source reclosing- When deciding whether to use the strong source or the weak source for reclose testing of the line there are several things to consider.

Generators- Utility Companies generally decide not to reclose the end of the line that is connected to a generator bus thinking that they do not want to stress generator more than necessary. However, this may not always be the best decision. If this line feeds a relatively weak system, reclosing from the remote end will typically take longer to clear depending on the fault. Even if the fault was cleared, this inrush and line charging will look like a load on the line and may cause voltage collapse and possible additional load shedding. In this example, if the line was closed from the strong source, the weak system would be spared the load shedding. If the fault was still there when closed from the strong source, it would have sufficient fault current to trip high speed. Also, if the line to be reclosed is not tied to a generator bus, faster clearing may still be the best choice from the stronger source and cause less disturbance to the system.

Autotransformers- A similar situation is encountered when re-energizing an autotransformer. Depending upon the relay package and system configuration of strong vs. weak sources, inrush when the autotransformer is being energized directly at the bus may result in tripping back out for the unbalance inrush, whereas closing end from a long line may limit the inrush and allow for a successful closing. In order to do this, additional switching may be required to drop all of the lines feeding the bus, close the auto into the dead bus, and then pick up the bus and autotransformer from the remote end of one of the lines.

Some relays now have functions that can be set and enabled to avoid this misoperation. Further details can also be found in C37.104 "IEEE Guide

for Automatic Reclosing of Line Circuit Breakers for AC Distribution and Transmission Lines" [20]

Sudden Pressure Relays (SPR) [or Fault Pressure Relays (FPR)]

Distribution Power Transformers, Power Plant Generator Start-up Transformers, and Autotransformers are usually equipped with a form of sudden pressure (or fault pressure) relays.

Unrelated to SPR are slow-gradual changes such as seen with a gradual loss of positive pressure. This tends to be related to seal integrity leaks, whereas a gradual buildup tends to be indicative of some gassing that is taking place and detected by other means.

On the other hand, when the transformer experiences an internal fault, the stresses inside the transformer winding coil assemblies tends to produce a pressure wave that is reflected throughout the transformer. This sudden pressure wave presses against the sudden pressure detection relay (typically a bladder and microswitch) that detects the sudden pressure wave and will change the microswitch contact position. For added security, a "c" form contact is usually used, such that the normally closed contact has to open, and the normally open contact has to close for which this sequence combination of actions are monitored by some form of relay system. While this action is most typically caused by an internal fault, a false indication is possible if the fault is a close-in external high magnitude fault. These sudden pressure relays tend to be on the main tank, and in the case of the autotransformer, one is usually also in the tap changer compartment as well.

Different utility companies take different actions when this fault pressure action is detected

1. They may trip
2. They may alarm only
3. Actions 1&2 may be dependent upon the specific voltage or application or past history with a specific transformer or transformer type or tap changer type.

Maintenance testing on these devices vary. In general, the tripping has to be isolated prior to any testing. The oil chamber that houses the sudden pressure relay has to be valved off and the connection cable has to be disconnected. A monitor of the contact status has to be connected to know when the microswitch operates. A pressure testing device has to be used to apply and measure the test pressure being applied to see if the sudden pressure sensor is operating to manufacturer's specifications. After all cables are reconnected, there needs to be a functional test to see that when the sudden test pressure is applied that the contact actually operates the end device protection relay as desired which verifies that all the cable were reconnected properly.

Working Group K6 is working with NERC on potential future requirements that may include the Sudden Pressure Relay System as part of the maintenance of the protection system. Monitoring the operation of this device can provide data to aid analysis through an input to a MP based relay, Sequence of Events Recorder, or Digital Fault Recorder.

Thermal Imaging via Thermography Cameras:

Thermography tests or infrared imaging (IR) has been used for many years to detect heating of components and connections within power substations. The focus of IR is to detect temperature increases or temperature differences to locate a "Hot Spot" and then do preventative maintenance before this issue becomes a component failure.

Small, relatively inexpensive IR "guns or probes" can be used to detect such things as overheated components and connections in an AC or DC Load Center or the connections inside a piece of equipment.

On the other hand, the larger more advanced IR cameras, have been used to detect temperatures and contrasts from previous data, and even

foreign objects against the equipment under study. Such an example would be detection of the temperature contrast and picture of a raccoon nestled against a distribution power transformer inside a substation. This detection might point to the need to implement animal mitigation techniques and removal from the substation before it causes an outage.

A partial list of substation components routinely monitored include: power transformers, load tap changers, circuit breakers, bushings, lightning arresters, metering units, free standing current transformers, connections, and substation batteries.

Thermal imaging is usually performed by an individual with a hand held IR camera. With the advancement of technology, an automated monitoring system with permanently mounted IR cameras can perform this task remotely. This monitoring system can provide early detection of impending equipment failures and also sense intrusion or security breaches. Remote trending of this data can be used to monitor the specific condition of an abnormal device while waiting for a replacement to be obtained and installed.

One example to consider would be given that the substation had major bulk power lines with free standing combination metering units that were exhibiting high temperatures. Closely monitoring and trending of the data might allow the equipment to be left in service rather than switch out a major line that could further jeopardize the dependability of the substation.

Security cameras are becoming common place in the substation, not only for intrusion, but to also view specific equipment for failures. Perhaps the time is at hand for IR systems to be deployed in high risk / high importance substations or ones that have troubled equipment.

Thus the IR camera could be employed reactively to a known problem, and also to proactively monitor equipment to detect if the safe threshold was being encroached upon.