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Predictive Maintenance Based on Protective Relays Data

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Predictive maintenance is becoming extremely important in the efforts of utilities to deal with reduced personnel and at the same time increasing customer requirements for improved power quality and reliable supply of electric power. Modern microprocessor-based relays measure and calculate numerous analog parameters and provide additional monitoring functions that allow the transition from scheduled into event driven maintenance, without the need for addition of any specialized equipment.

The paper presents a variety of tools, available in microprocessor based relays, that can help the utility to determine the need for substation equipment maintenance based on user defined alarm signals from the protective device.

The data is divided in several categories:

- Breaker maintenance related data, including breaker interrupted current, breaker operation counters, fault counters and breaker opening and close time monitors
- Breaker auxiliary contacts and trip coil monitor schemes
- Voltage transformer supervision schemes for single phase, two phase or three phase failure
- Current transformer supervision logic for the detection of problems with current transformers
- Broken conductor detection
- Fault locator
- Fault and disturbance recording

All the above information is available from the relays based on built in analysis tools that process the fault data and convert it to ready to use information, thus reducing the need for protection, control and maintenance personnel in the decision process.

The relays implement different algorithms based on recorded or measured samples of currents and voltages. Some of the recorded samples are used for the continuous calculation of superimposed quantities of the currents and voltages for faulted phase selection, and transient energy based directional detection.

Modern relays provide advanced monitoring functions that allow the detection of problems in the analog circuits based on the continuously measured currents and voltages. Advanced methods for the detection of 3 phase voltage failure are also possible when using the calculated superimposed currents.

Other recorded data is used for post-fault analysis in order to calculate the fault location and fault resistance.

Predictive maintenance

When we discuss maintenance in the paper we consider several types of maintenance:

- Substation equipment maintenance
- Transmission and distribution line maintenance
- Protective relays maintenance

Each of the above in the past was done based on pre-defined schedules, i.e., on fixed periods of times. It is known as "Scheduled Maintenance".

Significant changes in the power utility industry are driving the requirement for change in this previously common practice. These include reduced budgets, reduced number of qualified employees and at the same time increased work load.

Another common sense factor is the use of the " If it is not broken, don't fix it!" principle. There are many real life examples in which errors that occur during preventive maintenance caused significant system or equipment problems.

It may not be possible to eliminate preventive maintenance on all elements of the electric power system, since the failure of some equipment can have severe consequences. However, it can be modified without losing the basic idea to "If it doesn't tell you, don't fix it " principle. What this means is that different monitoring and analysis functions inside the protective relay can detect problems with the protected equipment or it's associated devices or analog circuits and based on user defined criteria "predict" the need for maintenance.

As a result of using such technology, the utility can change its maintenance practice from "scheduled maintenance" to "predictive maintenance"

Circuit Breaker State Monitoring Features

The relays can be set to monitor both the normally open (52a) and normally closed (52b) auxiliary contacts of the circuit breaker. Under healthy conditions, these contacts will be in opposite states. Should both sets of contacts have the same state - either opened or closed, this would indicate some problem with the breaker state indication.

If both contacts are open, one of the following conditions is the probable cause:

· Auxiliary contacts or wiring are defective

· Circuit Breaker (CB) is defective

· CB is in isolated position

Should both sets of contacts be closed, only one of the following two conditions would apply:

· Auxiliary contacts or wiring are defective

· Circuit Breaker (CB) is defective

If any of the above conditions exist, an alarm will be issued after a time delay. A normally open / normally closed output contact can be assigned to this function via the programmable scheme logic (PSL). The time delay is set to avoid unwanted operation during normal switching duties.

The Breaker State Monitoring function can be achieved based on a different setting of the protective relay. This cell can be set at one of the following four options:

- None
- 52A
- 52B
- Both 52A and 52B

Where 'None' is selected no Breaker Status will be available. This will directly affect any function within the relay that requires this signal, for example breaker control, auto-reclose, etc. Where only a 52A is used on its own then the relay will assume a 52B signal from the absence of the 52A signal. Circuit breaker status information will be available in this case but no discrepancy alarm will be available. The above is also true where only a 52B is used.

If both 52A and 52B are used then status information will be available and in addition a discrepancy alarm will be possible as described above.

Where single pole tripping is used, then an open breaker condition will only be given if all three phases indicate an open condition.

Similarly for a closed breaker condition indication that all three phases are closed must be given. For single pole tripping applications 52A-a, 52A-b and 52A-c and/or 52B-a, 52B-b and 52B-c inputs should be used.

Circuit Breaker Condition Monitoring

Periodic maintenance of circuit breakers is necessary to ensure that the trip circuit and mechanism operate correctly, and also that the interrupting capability has not been compromised due to previous fault interruptions. Generally, such maintenance is based on a fixed time interval, or a fixed number of fault current interruptions.

These methods of monitoring circuit breaker condition give a rough guide only and can lead to excessive maintenance.

The relay records various statistics related to each circuit breaker trip operation, allowing a more accurate assessment of the circuit breaker condition to be determined and, based on this, to predict when maintenance will be required. These monitoring features are discussed in the following section.

Circuit breaker condition monitoring features

Circuit breakers are designed to trip in a number of cycles - for example two or five cycle breakers. Monitoring and evaluation of the breaker operating time based on built-in analysis of the relay data can provide valuable information in order to predict the need for breaker maintenance. Slowing down of the breaker above a defined threshold will operate an alarm and will force the check of the breaker mechanisms to avoid potential breaker failure with its severe consequences.

The analysis of the breakers operations and the severity of the faults cleared can determine other breaker maintenance requirements. The latter is based on the fault currents data recorded by the relay.

For each circuit breaker trip operation the relay records statistics as described below. These usually are counter values only. Minimum and Maximum values are required in order to allow the user to set the range of the counter values for alarm thresholds.

The above counters may be reset to zero, for example, following a maintenance inspection and overhaul.

The circuit breaker condition monitoring counters will be updated every time the relay issues a trip command. In cases where the breaker is tripped by an external protection device it is also possible to update the breaker condition monitoring. This is achieved by allocating one of the relays opto-isolated inputs (via the programmable scheme logic) to accept a trigger from an external device. The signal that is mapped to the opto is called 'External Trip'. However, it is important to note that when in commissioning test mode the breaker condition monitoring counters should not be updated.

In the cases where overhead lines are subject to frequent faults and are protected by oil circuit breakers, oil processing accounts for a large proportion of the life cycle cost of the switchgear. Generally, oil processing is performed at a fixed interval of circuit breaker fault operations. However, this may result in premature maintenance where fault currents tend to be low, and hence oil degradation is slower than expected.

A good criteria that monitors the cumulative severity of the duty placed on the interrupting device allows a more accurate assessment of the circuit breaker condition to be made.

For oil circuit breakers the dielectric withstand of the oil generally decreases as a function of $\sum I^2 t$. This is where 'I' is the fault current broken, and 't' is the arcing time within the interrupter tank (not the interrupting time). As the arcing time cannot be determined accurately, the relay would normally be set to monitor the sum of the broken current squared, i.e. $\sum I^2$.

For other types of circuit breaker, especially those operating on higher voltage systems, practical evidence suggests that the value of the squared broken current may be inappropriate. In such applications instead of the broken current at the power of 2 it should be calculated at a lower power, typically 1.4 or 1.5. An alarm in the case when $\sum I^{1.5}$ is above the breaker manufacturer specified setting may be indicative of the need for gas/vacuum breaker HV pressure testing, for example.

The setting range for the exponential of the broken current for the maintenance alarm is variable between 1.0 and 2.0. It is imperative that any maintenance program must be fully compliant with the breaker manufacturer's instructions.

Another criteria that can be combined with the interrupted current monitoring is the Number of Operations. Every operation of a circuit breaker results in some degree of wear for its components. Thus, routine maintenance, such as oiling of mechanisms, may be based upon the number of operations. Suitable setting of the maintenance threshold will allow an alarm to be raised, indicating when preventative maintenance is due.

Should maintenance not be carried out, the relay can be set to lockout the autoreclose function on reaching a second operations threshold. This prevents further reclosure when the circuit breaker has not been maintained to the standard demanded by the switchgear manufacturer's maintenance instructions.

If the utility philosophy is to perform maintenance based on the number of breaker operations under fault conditions, a maintenance alarm threshold may be set to indicate the requirement for oil sampling for dielectric testing, or for more comprehensive maintenance. If maintenance has not been performed and the appropriate counters reset, the relay may be set to disable autoreclosure when repeated further fault interruptions could not be guaranteed. This minimizes the risk of oil fires or explosion. Exceeding the set number of operations is also indicative of the need for mechanism maintenance.

A circuit breaker may be rated to break fault current a set number of times before maintenance is required. However, successive circuit breaker operations in a short period of time may result in the need for increased maintenance. For this reason it is possible to set a frequent operations counter on the relay which allows the number of operations over a set time period to be monitored. A separate alarm and lockout threshold would also be available.

A different kind of maintenance is related to preventing high impedance faults when tree branches get into the distribution or transmission line, or the arcing of dirty insulators. A combination of the fault frequency counter and the fault location information provided by the relay can be used to determine the location and predict the need for branch trimming or insulator cleaning.

Fault Locator

The relay has an integral fault locator that uses information from the current and voltage inputs to provide a distance to fault measurement. The sampled data from the analog input circuits is written to a cyclic buffer until a fault condition is detected. The data in the input buffer is then held to allow the fault calculation to be made. When the fault calculation is complete the fault location information is available in the relay fault record.

Distance to fault is available in km, miles, impedance or percentage of line length. The fault locator should be able to store data for several faults. This ensures that fault location can be calculated for all shots on a typical multiple reclose sequence, while also retaining data for at least the previous fault.

When applied to parallel circuits mutual flux coupling can alter the impedance seen by the fault locator. The coupling will contain positive, negative and zero sequence components. In practice the positive and negative sequence coupling is insignificant.

Using a mutual compensation feature can eliminate the effect on the fault locator of the zero sequence mutual coupling. This requires that the residual current on the parallel line be measured. It is extremely important that the polarity of connection for the mutual CT input is correct.

A very helpful feature related to predicting the need for line maintenance is the availability of the fault resistance calculation as part of the fault location algorithm. An iterative algorithm using consecutive samples and based on Gouss - Seidel's method allows the simultaneous calculation of the distance to the fault and the fault resistance.

The fault resistance information can help determine the cause of the fault and the requirements for line maintenance.

The accuracy of the fault location calculation by the relay at one end of the line is affected by other factors, such as the load current, fault resistance and the infeed from the remote end.

Two ended fault location calculation algorithms should be used for further processing of the disturbance recording data available in the memory of the relay. This requires adequate synchronization of the samples from the relays at both ends of the protected line. This is possible to achieve when the disturbance records are time stamped with the 1-millisecond resolution available through the IRIG-B input of the relay.

Voltage Transformer Supervision (VTS)

The voltage transformer supervision (VTS) feature is used to detect failure of the ac voltage inputs to the relay. Internal voltage transformer faults, overloading or faults on the interconnecting wiring to relays or fuse failure may cause this failure. Another cause may be human error during maintenance or VT circuit switching.

Following a failure of the ac voltage input there would be a misrepresentation of the phase voltages on the power system, as measured by the relay, which may result in an undesirable operation.

The VTS logic in the relay is designed to detect the voltage failure, and automatically adjust the configuration of protection elements whose stability would otherwise be compromised. There are three main aspects to consider regarding the failure of the VT supply.

These are defined below:

1. Loss of one or two phase voltages

2. Loss of all three phase voltages under load conditions

3. Absence of three phase voltages upon line energization

Loss of one or two phase voltages

The VTS feature within the relay operates on detection of residual voltage without the presence of zero and negative phase sequence current, and ground fault current. This gives operation for the loss of one or two phase voltages. Stability of the VTS function is assured during system fault conditions, by the presence of zero sequence and/or negative sequence current. Also, VTS operation is blocked when any phase current exceeds 2.5 x In.

Loss of all three phase voltages under load conditions

Under the loss of all three phase voltages to the relay, there will be no zero phase sequence quantities present to operate the VTS function. However, if this collapse of the three phase voltages occurs without a corresponding change in any of the phase current signals (which would be indicative of a fault), then a VTS condition will be raised. The relay detects the presence of superimposed current signals, which are changes in the current applied to the relay. These signals are generated by comparison of the present value of the current with that exactly one cycle previously recorded and stored in the relay memory. Under normal load conditions, the value of superimposed current should therefore be zero. Under a fault condition a superimposed current signal will be generated which will prevent operation of the VTS.

Absence of three phase voltages upon line energization

If a VT were inadvertently left isolated prior to line energization, incorrect operation of voltage dependent elements could result. The previous VTS element detected three phase VT failure by absence of all three phase voltages with no corresponding change in current. On line energization there will, however, be a change in current (as a result of load or line charging current for example). An alternative method of detecting 3 phase VT failure is therefore required on line energization. The absence of measured voltage on all 3 phases on line energization can be as a result of 2 conditions. The first is a three-phase VT failure and the second is a switch into a close up three phase fault.

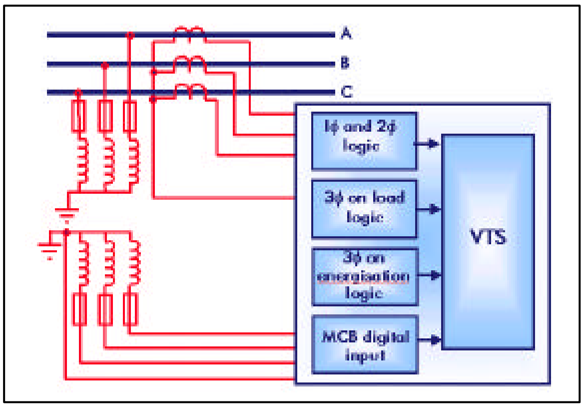

Figure 1 Voltage transformer supervision logic

The first condition would require blocking of the voltage dependent function and the second would require tripping. To differentiate between these 2 conditions an overcurrent level detector should be used which will prevent a VTS block from being issued if it operates. This element should be set in excess of any non-fault based currents on line energization (load, line charging current, transformer inrush current if applicable) but below the level of current produced by a close-up 3 phase fault. If the line is now closed where a 3 phase VT failure is present the overcurrent detector will not operate and a VTS block will be applied. Closing onto a three-phase fault will result in operation of the overcurrent detector and prevent a VTS block being applied.

Any operation of the Voltage Transformer Supervision logic will indicate the need for maintenance of the voltage circuit of the relay.

Current Transformer Supervision (CTS)

The current transformer supervision feature is used to detect failure of one or more of the ac phase current inputs to the relay. Failure of a phase CT or an open circuit of the interconnecting wiring can result in incorrect operation of any current operated element. Additionally, interruption in the ac current circuits risks dangerous CT secondary voltages being generated.

The CT supervision feature operates on detection of derived zero sequence current, in the absence of corresponding derived zero sequence voltage that would normally accompany it.

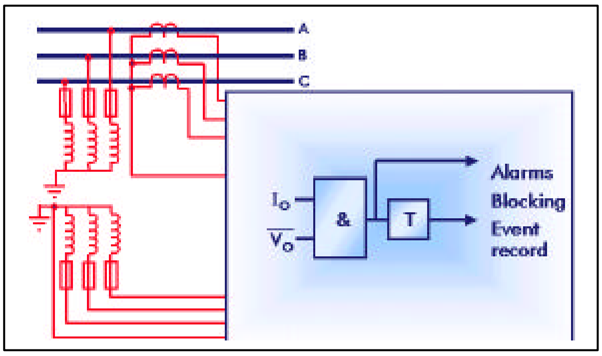

Figure 2 Current transformer supervision logic

The voltage transformer connection used must be able to refer zero sequence voltages from the primary to the secondary side. Thus, this element should only be enabled where the VT is of five limb construction, or comprises three single phase units, and has the primary wye point grounded.

Operation of the element will produce a time-delayed alarm and instantaneous block for inhibition of protection elements. Protection elements operating from derived quantities (Broken Conductor, Ground Fault, Negative Sequence Overcurrent) should always be blocked on operation of the CT supervision element.

Fault Records

Advanced microprocessor relays perform continuous monitoring of their hardware, software and the relay environment. Any changes are detected, analyzed, time stamped and recorded for further processing if necessary.

These records consist of fault flags, fault location, fault measurements, etc. Also note that the time stamp given in the fault record itself will be more accurate than the corresponding stamp given in the event record as the event is logged some time after the actual fault record is generated.

Maintenance and Event Records

Internal failures detected by the self-monitoring circuitry, such as watchdog failure, field voltage failure, etc., are logged into a maintenance report.

Each entry consists of a self explanatory text string that describes the type of failure and can be used to determine the required relay maintenance.

Each time a Maintenance Report is generated, an event is also created. The event simply states that a report was generated, with a corresponding time stamp.

Disturbance records

The integral disturbance recorder has an area of memory specifically set aside for record storage. The number of records that may be stored is dependent upon the selected recording duration and the recording mode selected by the user. Disturbance records continue to be recorded until the available memory is exhausted, at which time the oldest record(s) are overwritten to make space for the newest one.

The recorder stores samples that are taken at the relay sampling rate and before the filtering, in order to provide the actual fault conditions.

Each disturbance record consists of the available analog data channels (this is a function of the type of relay) and multiple digital data channels that give the status of inputs, outputs and different protection elements.

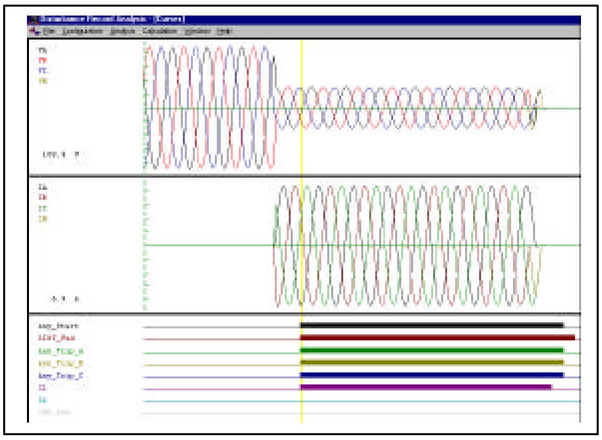

Figure 3 Disturbance record from the relay

The pre- and post-fault recording times are defined by the total length of the record and the trigger position. If a further trigger occurs while a recording is taking place, the recorder will ignore the trigger if the ‘Trigger Mode’ has been set to ‘Single’. However, if this has been set to ‘Extended’, the post trigger timer will be reset to zero, thereby extending the recording time.

The digital channels may be mapped to any of the opto-isolated inputs or output contacts, in addition to a number of internal relay digital signals, such as protection starts, LED’s etc.

Any of the digital channels may be selected to trigger the disturbance recorder on either a low to high or a high to low transition, via an ‘Input Trigger’ cell.

Conclusions

Advanced microprocessor-based protective relays are an important component in a distributed intelligence architecture for the first level of analysis of load and fault data. This converts the ever increasing amount of data from these intelligent electronic devices into information that can be used by the utility to switch from scheduled to predictive maintenance.

Continually recorded and sampled data is used to calculate superimposed components of the currents and voltages in order to determine faulted phases and transient energy-based directional detection. They also identify the existence of a fault condition that blocks the relay from issuing a three phase voltage failure.

Monitoring of the sequence components of the currents and voltages is used in the voltage and current transformer supervision logic of the relay to predict the need for maintenance in the analog circuits interfacing the relay with the substation primary equipment.

Breaker auxiliary contacts monitoring, calculation and integration of the breaker interrupted current to the power of a settable parameter, as well as the use of fault and trip operation counters allows the relays to accurately predict the need and type of required breaker maintenance.

Fault frequency data combined with the fault location and fault resistance calculated by the relay can be used to determine the need for distribution or transmission line maintenance such as tree trimming or cleaning of dirty insulators.

Single or extended trigger disturbance records in a COMTRADE format are a tool for further analysis of the fault and can be also used for protection functions testing when the need for relay maintenance is determined.

All of the above shows that the availability of advanced monitoring, recording and analysis functions gives the user valuable tools for improving the efficiency and reducing the cost of maintenance in the electric power system.

BIOGRAPHIES

Alexander Apostolov received MSEE, MSAM and Ph.D. from the Technical University in Sofia, Bulgaria. He worked for fourteen years in the Protection and Control Section of Energoproject Research and Design Institute, Sofia, Bulgaria.

From 1990-94 he was Lead Engineer in the Protection Engineering Group, New York State Electric & Gas where he worked on the protection of the six-phase line, application of microprocessor relays, programmable logic and artificial intelligence in protection. 1994-95 he was Manager of Relay Applications Engineering at Rochester - Integrated Systems Division. 1995-96, he was Principal Engineer at Tasnet. He is presently Western Region Engineering Manager for ALSTOM T&D. He is a Senior Member of IEEE and Member of the Power Systems Relaying Committee and Substations Subcommittee. He serves on several IEEE PES Working Groups and is Chairman of Working Group C3: New Technology Related to Power Systems Protection. He holds three patents and has authored more than 80 technical papers.

Rick Taylor attended Louisiana Tech University and received a BSEE cum Laude. He is Member of Tau Beta Pi and Eta Kappa Nu and Registered Professional Engineer in North Carolina and Louisiana. He worked for Louisiana Power & Light Co. in areas of protective relaying for 22+ years (1969-1991), ending as Manager of Protective Relaying for last 13 years. Currently he is Marketing Manager for ALSTOM T&D. He is a Senior Member of IEEE, Secretary of IEEE Power System Relaying Committee, Past Chairman of Line Protection Subcommittee, Past Chairman of Protective Relaying Performance Criteria Working Group (Winner of Outstanding Working Group award for 1993) and Past Chairman of Effectiveness of Distribution Protection Working Group. He is also a member of the planning committees for the relay conferences at Georgia Tech, Texas A&M and the WPRC in Spokane.