CIGRE SC B5 Protection and Automation

B5 is one of 16 Study committees of CIGRE. Its scope is to facilitate and promote the progress of protection and automation.

THE BUSINESS ENVIRONMENT FOR UTILITIES HAS CHANGED DRASTICALLY due to the restructuring of the world electrical energy markets. The profitability pressure has demanded reconsideration of the complete secondary system approaches, to identify and beneficially utilise all possible synergies between the tasks of protection, control and monitoring. All assets have to be used in more profitable ways, whilst the security of on-demand energy supply is increasingly important, due to the increasing costs for energy not supplied and the severe impacts that blackouts now have on communities, industry, commerce and nations. SC B5 covers all the secondary equipment and systems installed within substations. This includes power system protection, substation local and remote control, automation, metering, monitoring and recording.

Priorities

Automation of substations, with integrated protection and control systems and the use of the new IEC 61850 Standard are major industry trends. The application of IEC 61850 will be extended to further areas and its impact will demand continued review and study to detect any general problems, so that they can be addressed before they become too widespread. CIGRE SC B5 provides a unique channel of feedback to IEC in this respect.

by Ivan De Mesmaeker, ABB, Switzerland

Relevant issues related to the IEC 61850 standard are:

- Functional testing of IEC 61850 based systems
- Application of protection schemes based on IEC 61850
- Engineering Guidelines for IEC 61850 based systems
- Maintenance strategies for Substation Automation Systems
- Impact of security requirements on SAS

The introduction of digital hardware and numerical protection technology has greatly transformed the planning, operation and maintenance practices for protection systems. Design engineers now require appropriately adapted guidelines to support their work. Several working groups are preparing reports about on-going trends and offering recommendations for the protection of generators, transformers, shunt reactors, overhead lines or cables and busbars.

Modern numerical relays are highly integrated and contain a great number of protection and additional functions. Special attention is given to the increasing trend for functional integration. "Bay Units" for combined protection and control are now accepted at distribution levels and this trend may migrate to the transmission levels. Numerical relays are widely self-monitored. Regular routine testing will therefore be increasingly replaced by condition-based maintenance, depending on how comprehensive the self-monitoring is.

System-wide monitoring and protection

Wide area disturbances due to loss of stability or voltage collapse, still occur and may become more probable in the future, with higher system loading and by regularly operating plant and power systems towards their design limits and capabilities. On the other hand, wide-band communication links, adaptive digital protection and GPS synchronized data acquisition provide platforms for novel system wide monitoring and protection techniques. In many countries a large part of the business is the retrofitting of existing plants and systems because of life-expiry, or because of recommendations about the need to change current practices. The development of life-cycle maintenance and risk management strategies are therefore expected.

Communications within substations are covered by the new and expanding IEC 61850 standard.

Software tools for dynamic simulation, management of relay settings, disturbance or fault record analysis, or how to write specifications are improving.

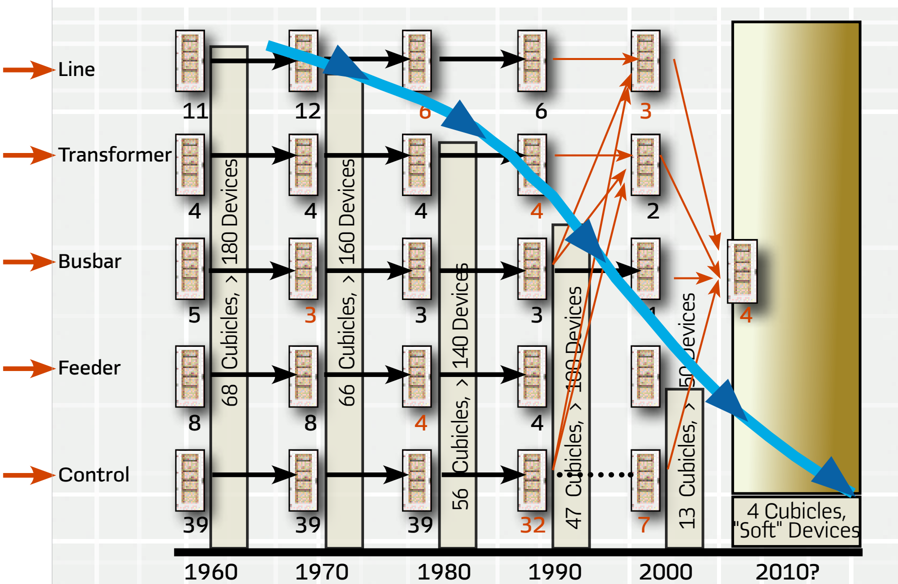
Emphasis on education is a challenge, considering that protection is generally not a topic dealt with to any significant depth by colleges and universities, and that engineers entering in the power engineering sector in general are becoming rare.

Numerical technology combined with advances in information management contributes to the more efficient management of power networks, but it introduces problems and issues in four main areas: level of integration, standardisation, information management, wide area monitoring and protection.

The integration of ever more functions into fewer devices and systems has been an increasing trend – especially over the last 10 years or so. Figure 1 indicates the evolution of the number of devices for a protection and control system covering a station with six 220 kV lines and eight 16 kV feeders.

Protection function integration is now the norm and combined with high level of self-supervision in numerical protection devices actually supports a higher degree of integration - a trend that will continue in the future.

1 Evolution of number of devices for a protection and control system



The modern protection technology facilitates new solutions and functions to tackle several fault management problems, such as the protection of combined cable-overhead lines (adaptive auto reclosing with ability to distinguish potentially transient overhead line arcing faults from solid cable faults) or the protection of parallel and/or multi-terminal lines.

Standardization

Standardization covers two main aspects: Typical Bay and Station levels and Communication.

Independently of the applied technology, it is possible to define the required functionality and performance of each protection and control function (tripping times, precision, etc) for each type of Bay, in each type of substation. Users can define additional requirements, such as the permitted level of functional integration, the physical scheme architecture, the requirements concerning DC auxiliary/tripping supplies, test facilities, wiring and inclusion of some specific devices. Functional requirements can also be listed at the Station level, covering HMI (Human Machine Interface), event and alarm lists, etc.

Specifications need only be functionality based, with reference to a single line diagram, rather than detailing specific protection system devices.

Communications

Communications in substations should assure interoperability between compliant Intelligent Electronic Devices and functions within the substation. They should be future-proofed, i.e. able to cope with the fast developments in communication technology compared to the more slowly evolving application domain of power systems.

These are very ambitious goals, which demand that all secondary substation devices and functions must be examined with regard to their communication performance and requirements. ■

Guide for Breaker Failure Protection Published

The Power System Relaying Comettee is in the Power Engineering Society of IEEE.

by Roger Hedding, ABB, USA

How do utilities handle backup protection? What are the advantages of using local backup over remote backup? How is breaker failure protection being implemented by utilities? What are the pitfalls in using the breaker auxiliary contact for breaker position? Where do you go to get these answers? Prior to 2005 no guide existed in applying breaker failure protection to answer any of these questions. The only previous article written by the PSRC was in 1982. An IEEE Power System Relaying Committee Working Group wrote a report titled "Summary Update of Practices on Breaker Failure Protection" and published it in the IEEE Transactions on Power Apparatus and Systems. Vol. PAS 101, no.3, pp 555-563. March 1982.

To answer these questions and provide a reference for engineers to for future generations, the IEEE PES PSRC Substation Subcommittee formed a working group to write a guide on this subject. This working group was formed in 2000. 62 industry experts from utilities, manufacturers, academia and government agencies put in many hours of effort in writing and reviewing the guide before it was published in 2005. The result is IEEE STD C37.119 Guide for Breaker Failure Protection of Power Circuit Breakers – 2005. The following are excerpts from the guide Remote versus Local Backup.

If remote backup is employed, then the time delayed overreaching element (Z2) of the relay at a remote substation operates for a fault on line BC when local breaker fails to clear the fault on a line. Operation of remote breaker interrupts the load connected downstream of it. If local backup is used, when a breaker fails, local breakers clear the fault. The load is not interrupted in this case on the line with the remote substation. Local backup provides faster clearing and less loss of load than remote backup:

In the basic scheme for breaker failure protection, as soon as the relay issues a trip to its breaker, a breaker failure timer is started. If the fault still persists after the timer times out, then a breaker failure condition is declared, and the breakers connected to the bus are tripped.

Breaker Failure Initiate (BFI) is the signal coming from the primary

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IEEE C37.119 Guide for Breaker Failure Protection

protection to trip the breaker. An overcurrent fault detector (50BF) is employed to determine if the fault is still present. 50BF will drop out if the breaker clears the fault. The guide discusses issues related to the setting and drop out of the fault detector (50BF). The timing for the scheme is seen below. (Fig. 1)

In EHV transmission systems, the total fault clearing time needs to be less then the power system critical clearing time plus some margin. The power system critical clearing time is a function of the steady state stability limit for the power system. Since the critical clearing time to maintain system stability is greater for single line to ground faults than three phase faults, some schemes employ dual timers. (Fig. 3) The 62-2 timer can be much longer than 62-1.

For lower voltage systems, the total clearing time is chosen to limit damage to equipment. Some faults such as transformer or reactor faults have such small currents that a fault detector can not be used. In those cases, a breaker 52b contact is used for indication of breaker operation. (Fig. 4) In some cases where there is a known problem with a breaker before it's called to trip, a bypass scheme can be employed. (Fig. 5)

In this scheme, if there is low gas pressure and the primary relay calls for a trip, the breaker failure scheme is bypassed and the surrounding breakers are tripped immediately. Other schemes are also discussed.

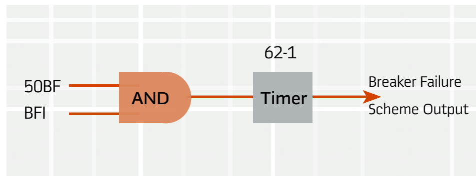
A section of the guide deals with design considerations for the breaker failure scheme. Several factors need to be considered. *Among them:*

- Scheme operation should only occur when expected and desired.
- Scheme operation should be independent of the types of failures detected in the breaker. For example, the failure mode of the breaker trip coil should not effect the schemes ability to detect the failed breaker and to properly isolate it from the power system.
- Scheme operation during loss of dc power to the failed breaker.
- Sufficient overlapping of protection and isolation switches to allow maintenance and overall testing of the scheme.
- Proper application of auxiliary tripping relays.
- Selection of properly rated inputs and outputs when the breaker failure is integrated as part of the equipment protection package and when user selectivity in rating is provided.
- Proper application of dc circuits and avoidance of mixing supply sources.
- Minimizing the impact of dc transients.

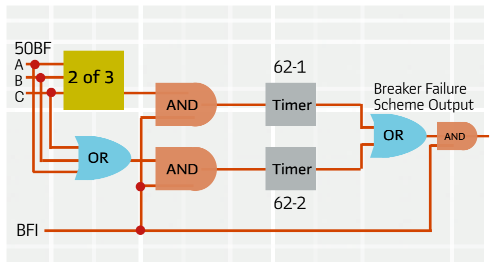
Other sections of the Guide deal with factors that influence settings, communications based breaker failure schemes, and end to end testing.

The guide is available through the IEEE Standards Department

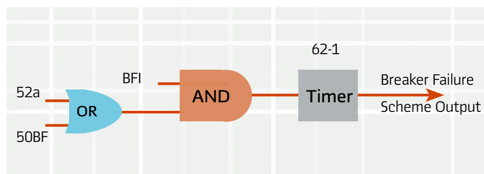
2 Basic Breaker Failure Protection scheme



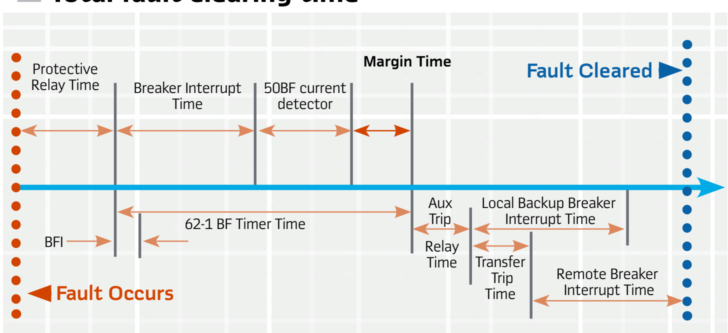
3 Dual-Timer Breaker Failure Protection scheme



4 Breaker contact use for breaker operation detection



1 Total fault clearing time



5 BFP bypass scheme